L/ham

MAIL DATE
6/24/03

Decision 03-06-076 June 19, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development	R.01-10-024 (Filed on October 25, 2001)

ORDER MODIFYING DECISIONS 02-10-062 AND 02-12-074 AND DENYING REHEARING

I. INTRODUCTION

In D.02-10-062 (the October decision), the Commission adopted a regulatory framework under which Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas and Electric Company (SDG&E) were to resume full procurement responsibilities effective January 1, 2003. Among other things, that decision required the utilities to file updated short-term procurement plans, which were approved by the Commission in D.02-12-074 (the December decision). [1]

These decisions were issued pursuant to Assembly Bill (AB) 57 and Senate Bill (SB) 1976, which became effective on September 24, 2002 and were codified as Public Utilities Code section 454.5.[2] Public Utilities section 454.5 was enacted to provide guidelines for the prospective procurement of electricity by electrical corporations, and to ensure that electrical corporations whose customers were being

[1] Because many of the same issues are raised in the applications for rehearing of D.02-10-062 and D.02-12-074, these decisions are addressed together in this order.

[2] AB 57 and SB 1976 added identical versions of section 454.5 to the Public Utilities Code, except that SB 1976 requires an electrical corporation to resume procurement 60 days after the Commission adopts a procurement plan for that corporation, rather than 90 days. The two bills also differ in that the intent section of AB 57 focuses on prospective procurement of electricity by electrical corporations, while the intent section of SB 1976 addresses the goals of energy conservation and demand reduction.

served by the Department of Water Resources (DWR) would resume procurement of electricity by January 1, 2003. (Assem. Bill No. 57 (2001-2002- Reg. Sess.) § 1(a), (b).)

Public Utilities Code section 454.5 contains many specific directives to the utilities and the Commission. First, the statute requires the Commission to allocate electricity provided under DWR's power purchase agreements to the customers of each electrical corporation and requires each electrical corporation to file a proposed procurement plan with the Commission. (§ 454.5(a).)

Second, the statute lists items that must be included in any proposed procurement plan. Among other things, an electrical corporation's proposed procurement plan must include: "The upfront standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to execution of the transaction," including an expedited approval process for the Commission's review of proposed contracts (§ 454.5(b)(7)) and a mechanism for recovery of "reasonable administrative costs related to procurement" in the generation component of rates (§ 454.5(b)(12)).

Third, the statute requires the Commission to review and accept, modify, or reject each electrical corporation's procurement plan. Pursuant to section 454.5(c), a procurement plan approved by the Commission "shall contain one or more of the following features," provided that the commission may not approve a feature if it finds that the feature "would impair the restoration of an electrical corporation's creditworthiness or would lead to deterioration of an electrical corporation's creditworthiness":

- A competitive procurement process under which electrical corporation may request bids for services. (§ 454.5(c)(1).)
- An incentive mechanism that establishes a procurement benchmark. (§ 454.5(c)(2).)
- Upfront achievable standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known

> by the electrical corporation prior to the execution of the bilateral contract for the transaction. (§ 454.5(c)(3).)

Fourth, the statute provides that a procurement plan approved by the Commission shall accomplish each the following objectives:

- Enable the electrical corporation to fulfill its obligation to serve its customers at just and reasonable prices. (§ 454.5(d)(1).)
- Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. (§ 454.5(d)(2).)
- Ensure timely recovery of prospective costs incurred pursuant to an approved procurement plan. (§ 454.5(d)(3).)
- Moderate the price risk associated with serving its retail customers, including the price risk embedded in its long-term supply contracts, by authorizing an electrical corporation to enter into financial and other electricity-related producer contracts. (§ 454.5(d)(4).)
- Provide for just and reasonable rates, with an appropriate balancing of price stability and price level in the electrical corporation's procurement plan. (§ 454.5(d)(5).)

The statute provides that the Commission has the authority to review and modify an electrical corporation's procurement plan. (§ 424.5(e).) Finally, the statute expressly acknowledges the Commission's continuing authority to oversee affiliate transactions, to investigate and penalize utility fraud, and to disallow costs incurred as a result of gross incompetence, fraud, abuse, or similar grounds. (§ 424.5 (h).)

In the October decision, one of a series of decisions implementing section 454.5, the Commission adopted a framework designed to enable the three investor-owned utilities (IOUs) to resume full procurement responsibilities effective January 1, 2003. The framework required PG&E, Edison, and SDG&E (collectively, the IOUs) to file modified short-term procurement plans by November 12, 2002 for the Commission's review, and outlined an expedited review procedure and timely recovery mechanisms. Guidance was provided regarding long-term procurement planning, and the IOUs were directed to file their long-term plans by April 1, 2003.[3]

The Commission's previously issued directive to procure an additional one percent of renewable energy (see D.01-08-071) was integrated with the procurement planning directives. The Commission also adopted "minimum standards of behavior" (also referred to as Standards of Conduct) for the utilities to follow in creating and implementing their procurement plans. Finally, the October decision imposed a temporary two-year moratorium on affiliate transactions for procurement purposes, pending an updating of the Commission's affiliate transactions rules.

Applications for rehearing of the October decision were filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), San Diego Gas and Electric Company (SDG&E), Sempra Energy Resources (Sempra), and Cogeneration Association of California (CAC). The applications raise numerous legal objections to the decision. The IOUs' primary focus is on the Standards of Conduct, claiming that they are illegal, impractical, and/or unnecessary. In particular, the applicants object to Standard 4, the least-cost dispatch standard. The applicants allege that Standard 4 provides for "after-the-fact reasonableness review" of procurement contracts by the Commission, in violation of section 454.5. Applicants also contend that the record does not support the provisional 15 percent reserve level adopted by the Commission and that the temporary moratorium on affiliate transactions is unsupported and illegal. In addition to legal challenges, the applicants raise many objections based on

[3] An extension was later granted to April 15.

practical and policy considerations (which are not properly the subject of an application for rehearing).[4]

Responses were filed by The Utility Reform Network (TURN), the Center for Energy Efficiency and Renewable Technologies (CEERT), the California Biomass Energy Alliance (CBEA), and Consumers' Union.[5]

In the December decision, the Commission adopted, with modifications, the short-term procurement plans that PG&E, Edison, and SDG&E had filed pursuant to the October decision. The December decision also granted, in part, a petition filed by PG&E, which requested modification of the cost recovery mechanisms and standards of conduct adopted in the October decision.[6]

PG&E, Edison, San Diego, and Sempra filed applications for rehearing of the December decision. The applications incorporated or reiterated many of the arguments made in the applications for rehearing of the October decision. In particular, Sempra and the IOUs continued to challenge the Standards of Conduct, as modified by the December decision. Responses were filed by the Office of Ratepayer Advocates (ORA), Independent Energy Producers Association (IEP),[7] and CBEA.

We have reviewed each and every allegation of error raised in the applications for rehearing and are of the opinion that applicants have not demonstrated good cause of rehearing. However, we will modify the decisions as explained further below.

[4] Public Utilities Code section 1732 requires that applications for rehearing set forth specifically the ground or grounds on which the applicant considers the decision or order to be unlawful. See also Rule 86.1 of the Commission Rules of Practice and Procedure.)

[5] On December 2, 2002, Consumers Union filed a single document apparently intended to serve both as a petition for modification of the October decision *and* as a response to the IOUs' applications for rehearing of that decision.

[6] There have been numerous subsequent petitions to modify these decisions, some of which have been resolved and some of which are still pending.

[7] On February 5, 2003, IEP filed a single document responding both to the applications for rehearing of D.02-12-074 and to Edison's February 3, 2002 petition for modification of D.02-12-074.

II. DISCUSSION

A. Resumption of Procurement

1. Whether Requiring PG&E to Resume Procurement Violates the Creditworthiness Requirements of Public Utilities Code Section 454.5(c) and/or Due Process

PG&E argues that the October decision errs by requiring PG&E to resume procurement unconditionally, for the long-term, on January 1, 2003. In particular, PG&E notes that "the decision declines to set rates or to establish a ratemaking process for recovery of new procurement costs, but merely leaves those costs to be accumulated in a balancing [account] for future ratemaking." (PG&E App.Rhg. of D.02-10-062, pp. 6-7; see D.02-10-062, p. 59.) PG&E contends the decision thus violates Public Utilities Code section 454.5(c), which states that the Commission may not approve a mechanism as part of a procurement plan if it finds that such mechanism would impair the restoration of an electrical corporation's creditworthiness or would lead to a deterioration of an electrical corporation's creditworthiness.[8] PG&E also claims that the decision deprives PG&E of property without due process of law.

Because PG&E has resumed procurement, this issue appears to be moot. In court cases, an action originally based on a justiciable controversy cannot be maintained on appeal if the questions raised have become moot by subsequent acts or events. (*Finnie v. Town of Tiburon* (1988) 199 Cal.App.3d 1, 10.) When an event occurs that renders it impossible for the court, even if it decides in favor of a party, to grant any effectual relief to that party, the court will not proceed to a formal judgment. (*City of Los Angeles v. County of Los Angeles* (1983) 147 Cal. App.3d 952, 958.) Thus, whether an issue is

[8] We note that we do not interpret section 454.5(c)'s creditworthiness requirement as expansively as the utilities do. Section 454.5(c) only precludes the Commission from adopting one of the three listed features of a procurement plan (i.e., competitive procurement process, incentive mechanism and/or upfront achievable standards) if that feature would impair a utilities creditworthiness. Section 454.5(c) does not provide that every aspect of procurement must be measured against the creditworthiness standard.

moot depends, in part, on the relief requested. If PG&E is asking the Commission to relieve it from its obligation to procure power, the issue may be moot. On the other hand, if PG&E is requesting that the Commission place additional conditions or limitations on its procurement responsibilities, the issue would not be moot. Therefore, this order addresses the merits of PG&E's argument regarding the findings in the decision.

PG&E's argument of legal error centers on the decision's conclusion that the utilities do not need to be investment grade to resume procurement. Although the decision makes a number of findings to support its conclusion, PG&E argues that these findings are unsupported by the record or are otherwise erroneous.

First, the decision finds that many companies in the energy industry today do not have an investment grade credit rating and are nevertheless able to conduct business. (D.02-10-062, pp. 9, 66, FF 7.) PG&E argues that because the decision does not indicate what companies the Commission has in mind, there is no way to know if these "other companies" are reasonably comparable to a regulated utility with its obligation to serve. PG&E contends that this finding is meaningless and without evidentiary support, and cannot provide a basis for the conclusion that utilities do not need to be investment grade to resume procurement.

After a review of the record in this case, we agree that there does not appear to be evidence to support this factual finding. Therefore, we will delete finding of fact 7. Because this finding is merely one of several that we relied upon in ordering PG&E to resume procurement, elimination of this finding does not change our conclusion that PG&E is capable of resuming procurement.

Second, the decision finds that the testimony of suppliers indicates their willingness to enter into contracts with the utilities. (D.02-10-062, pp. 9-10, 66, FF 8.) PG&E does not dispute this finding.

Third, the decision finds that PG&E has a strong cash flow and a stable and secure revenue stream. (D.02-10-062, pp. 10, 67, FF 9.) PG&E contends that this finding ignores other factors. PG&E states that the ultimate disposition of the revenue stream is still subject to Commission determination in future proceedings on the use of surcharge revenues and the end of the rate freeze. PG&E also asserts that the same stream of cash represents the only financial resources PG&E has to support a variety of utility activities. However, PG&E does not dispute the finding that it has a strong cash flow and stable revenue stream, which is supported by the record in this case.

Fourth, the decision finds that, under the Commission's proposed reorganization plan, PG&E will be able to quickly emerge from bankruptcy as a creditworthy entity. (D.02-10-062, pp. 10, 67, FF 11.) PG&E states that this finding concerns the outcome of litigation in PG&E's bankruptcy proceeding that is "presently on-going and fiercely contested." (PG&E App. Rhg. of D.02-10-062, p. 9.) Thus, PG&E argues that the finding is a prediction and not a fact.

PG&E's argument has some merit. Therefore, we will delete this finding from the decision.

Fifth, the decision states that the residual net short that the utilities will face on January 1, 2003 is substantially less than what they faced in 2000, and that PG&E's needs are well within its ability to finance. (D.02-10-062, pp. 8-9, 67, FF 13, 14.) PG&E argues that the size of the residual net short does not mean that its costs will be small. Furthermore, according to PG&E, the costs of resuming procurement are not limited to the residual net short, but also include, among other things, the costs associated with disposing of surplus power under the DWR contracts. Although PG&E disputes the significance of the size of the residual net short, PG&E has failed to demonstrate that the decision's finding is without basis.

Finally, PG&E argues that the Commission itself has indicated that financially ill utilities cannot successfully procure and provide reliable, safe, electric service. PG&E quotes Decision 02-11-026, which states:

> While authorizing refunds and reducing rates might appear to benefit ratepayers, ratepayers and the economy are actually harmed when utilities are unable to procure and deliver reliable, safe and adequate electricity. No party presents a

> convincing argument that financially ill utilities are able to fulfill these public utility responsibilities and obligations.

(D.02-11-026, mimeo, p. 10.) That decision modified prior decisions that implemented surcharges in response to the 2000-2001 energy crisis, but restricted the use of such surcharges to ongoing procurement costs and future power purchases. D.02-11-026 concluded that the surcharges might be used to return each utility to financial health. The language quoted by PG&E was in response to arguments that use of the surcharges should continue to be restricted, and any that revenues not used for procurement should be refunded to ratepayers. It provides little or no support for PG&E's contention that the instant decision violates the creditworthiness requirements of section 454.5.

PG&E has failed to show that the decision, as modified, errs in concluding that the utilities do not need to be investment grade to resume procurement.

2. Whether The Decision Errs in Failing to Provide 60 Days Between Approval of the Revised Procurement Plans and the Utilities' Resumption of Procurement

Both PG&E and Edison contend that D.02-10-062 fails to provide 60 days between approval of the revised procurement plans and the utilities' resumption of procurement, in violation of section 454.5(a). Section 454.5(a) provides:

> After the Commission's adoption of a procurement plan, the Commission shall allow not less than 60 days before the electrical corporation resumes procurement pursuant to this section.

In the October decision, the Commission approved, with modifications, procurement plans that the utilities had filed on May 1, 2002. The decision notes that after the May 1 plans were filed, the Commission adopted D.02-08-071 (which authorized transitional procurement authority with DWR's credit support) and D.02-09-053 (which allocated DWR contracts to the utilities). The Commission directed the utilities to file modified short-term procurement plans on November 12, 2002, which were to include transitional procurement, the DWR contract allocation, and modifications made in the October decision. (D.02-10-062, pp. 14-17.) The first opportunity that the

Commission would have had to approve the modified plans would have been at the December 17, 2002 Commission meeting.[9] This allowed only about two weeks between the issuance of the December decision and January 1, 2003, the date on which the utilities were to resume procurement.

PG&E and Edison claim that the 60-day trigger only applies to the approval of the revised procurement plans that were filed on November 12, 2002. PG&E argues that approving a procurement plan that does not include the allocation of DWR power does not satisfy Public Utilities Code section 454.5(a), which states that the allocation of DWR electricity "shall be reflected in the electrical corporation's proposed procurement plan." Thus, PG&E contends that the May 1, 2002 plans cannot start the 60-day clock running.

TURN responds that, pursuant to the October decision, the Commission effectively adopted the utilities' procurement plans with modification on October 24, 2002 – a full 68 days prior to January 1, 2003, and also ordered the utilities to begin procurement on January 1, 2003. (See D.02-10-062, p. 74, OP l.) As for PG&E's claim that the 60-day trigger only applies to the approval of a procurement plan filed after the allocation of the DWR contracts, TURN contends that nothing in section 454.5(a) prohibits the utilities from filing procurement plans in advance of the contract allocation order.

This issue appears to be moot. Because PG&E and Edison began purchasing power as of January 1, 2003, and because the 60-day period has now expired, it is obviously impossible to delay the resumption of procurement. To the extent that PG&E or Edison is seeking such a remedy, this issue is moot.

However, Edison contends that, in addition to the issue of compliance with the statute, the decision raises significant practical problems As of the date of the decision, Edison's authorized procurement plan was its May 1 plan. However, according to Edison, that plan was replaced; on or about December 17 Edison will have a second

[9] The Commission actually approved the plans on December 19, 2002 in D.02-12-074.

authorized plan, the November 12 plan, which will not take effect until mid-February (60 days from approval). Thus, Edison asks what plan it should follow on January 1, 2003. Furthermore, Edison states that two weeks (between the December approval of the plan and January 1, 2003) are not enough time to implement the approved procurement plan. Edison's real concern appears to be that any transactions that occur during this so-called "twilight zone" (between January 1, 2003 and mid-February) are under no procurement plan and thus could be subject to reasonableness reviews. As TURN points out, the October decision approves the utilities' May 1, 2002 procurement plans, as modified by then-recent filings and the October decision. (D.02-10-062, p. 16.) Thus, we believe that we complied with the 60-day time period by approving the procurement plans in the October decision. Moreover, because Water Code section 80260 (ABX1 1) states that DWR shall not contract for the purchase of electrical power on or after January 1, 2003, the statutory scheme clearly supports directing the utilities to resume procurement by January 1. Nevertheless, we recognize that the May 1, 2002 plans did not include transitional procurement, the DWR allocation, and other modifications ordered in the October decision. (D.02-10-062 at pp. 16-17.)

Therefore, in the event that any future Commission review finds that actions taken by the utilities during the period from January 1, 2003 to February 17, 2003 (60 days after the adoption of D.02-12-074) were not in compliance with the approved procurement plans, the Commission will afford the utilities the opportunity to demonstrate that they did not have time to implement certain standards or that certain standards were not sufficiently clear when the utilities resumed procurement.

B. Standards of Conduct Governing Procurement: Moratorium on Affiliate Transactions

Sempra and PG&E object to the temporary moratorium on procurement from affiliates announced in our October decision. This measure was prompted by our concern that our current rules governing affiliate transactions, "which were designed for the regulatory world of AB 1890, not today's market structure" probably do not provide adequate safeguards with respect to procurement transactions. The moratorium was to be in place until we completed a re-examination and revision of our affiliate rules, which we expected to address in a rulemaking proceeding previously opened for that purpose (R.01-01-011). In the event the rules revision is not completed by the end of 2004, the temporary moratorium would be terminated at that time. (D.02-10-062, , pp. 49 and 68, FF 21.)

The moratorium does not preclude "transactions through the ISO [Independent System Operator] that can be demonstrated to include multiple and anonymous bidders." (FF 21.) In today's order, we expand that exception to include anonymous transactions (where the buyer does not know who the seller is and vice-versa until after agreement has been reached) conducted through brokers and exchanges. Today's order also clarifies that Standard of Conduct 1, regarding affiliate transactions, is not intended to preclude such blind transactions.

Both Sempra and PG&E contend that federal law preempts us from imposing a temporary moratorium on procurement from affiliates. For the reasons discussed below, we disagree. Sempra also contends that the moratorium is not supported by the record or by adequate findings and conclusions. The decision to impose a temporary moratorium is supported by substantial evidence. However, because the October decision included a very limited discussion of that evidence, by this order we amend it to expand that discussion and to add related findings. Sempra also claims that the moratorium violates constitutional rights to due process and equal protection, and the dormant commerce clause. These arguments, as well as the preemption argument, all lack merit. We address each of them in turn.

1. Record, Findings, and Conclusions Supporting the Moratorium

Sempra contends the temporary moratorium is not supported by the record or by the findings and conclusions required by Public Utilities Code section 1705. The October decision appropriately relies on the "disallowance exhibits" prepared by each of the three utilities at the request of Judge Walwyn. These exhibits list disallowances for procurement costs from 1980 to 1996 and cross-referenced the Commission decisions that disallowed those costs. (D.02-10-062, p. 49; Exhibits 73, 78, and 79 (Revised).) We stated that "the majority of these [Commission] decisions and dollar adjustments involved affiliate transactions." (D.02-10-062, p. 49.)

Sempra asserts, without explanation, that those conclusions are incorrect. Sempra appears to miss the point we were trying to make. These exhibits, together with the Commission decisions they reference, show that the largest disallowances for procurement costs, in terms of dollar amounts, involved affiliate transactions. This conclusion is confirmed, with respect to Edison, by Edison's own witness, Dr. John Jurewitz, who acknowledged that "the only disallowance that I see [in Edison's disallowance exhibit] that moved into the hundreds of millions was an affiliate transaction." (R.T. 16: 2069.) We infer from this information that even before restructuring of the electric industry, regulatory vigilance over procurement from utility affiliates was necessary.

Sempra argues that this evidence is irrelevant because the disallowances shown in these exhibits predate the current affiliate rules, which were revised in 1997, but we disagree.[10] The risk of inappropriate ratepayer subsidization of utility affiliates is, if anything, greater in the post-AB 1890 environment. Given that the utilities have divested themselves of much of the generating capacity they used to own, there is a much greater role for utility affiliates to play in energy procurement. In addition, with the elimination of after-the-fact reasonableness reviews pursuant to AB 57, up-front standards and safeguards are particularly important.

TURN, Aglet, and the Consumers Union submitted testimony and comments in this proceeding discussing the risks inherent in allowing utilities to buy power from their own affiliates within the current holding company structure. Consumers Union, through its witness William Ahern, argued that the best protection against the significant

---

[10] Sempra asserts that the record evidence establishes that no "affiliate abuses have occurred in the utility procurement process since the Affiliate Transaction Rules were promulgated" (Sempra App. Rhg. of D.02-10-062, p. 9), but does not explain how the evidence it cites supports this sweeping conclusion.

risk of affiliate abuses in procurement would be a structural separation of the utilities from their holding companies. (Exhibit 117, pp. 11-12.) TURN expressed particular concern that SDG&E "has been taken captive by its parent company." (Opening Brief of TURN on Procurement Issues, filed July 29, 2002.) "It is becoming increasingly clear that the interest of the unregulated affiliates are the driving factor behind SDG&E's official positions." (Opening Brief of TURN on Procurement Issues, filed July 29, 2002.) TURN cites three examples, including SDG&E's "weak position on direct access cost responsibility in R.02-01-011 due to the major financial interest in direct access held by Sempra Energy Solutions" and SDG&E's failure to challenge "overpriced contracts signed by DWR with Sempra Energy Resources." (Opening Brief of TURN on Procurement Issues, filed July 29, 2002, fn. 27.) These examples, which are in the record of this proceeding, illustrate the nature of the risks involved in utility procurement from its own affiliates.[11]

In addition, we recently opened our own investigation to determine whether business activities between SDG&E and Southern California Gas Company (SoCal Gas), on the one hand, and their holding company, Sempra Energy, complies with applicable statutes and decisions. As we stated in that proceeding, "unregulated affiliates of the respondent utilities have substantial business activities within the utilities' service territories that may create conflicts of interest between the utilities (and the utilities' ratepayers) and their unregulated affiliates." (I.03-02-033, Order Instituting Investigation whether SDG&E, SoCal Gas and their holding company Sempra Energy, respondents, have complied with relevant statutes and Commission decisions, pertaining to respondents' holding company systems and affiliate activities, p. 1.) More specifically, we noted that Sempra had requested Commission approval to participate in future sales of electricity to its affiliated regulated utility, SDG&E. (I.03-02-033, p. 3.)

---

[11] California's request to abrogate or modify the Sempra power contracts to which TURN refers is currently pending before the Federal Energy Regulatory Commission (FERC). We take official notice of this fact, on our own motion. (See Rule 73 of the Commission Rules of Practice and Procedure and Evidence Code § 452.)

The results of that investigation may also prove useful in determining what safeguards are necessary to ensure that ratepayer costs are not driven up as a result of conflicts of interest among affiliated entities involved in energy procurement.

The record supports the need for a temporary moratorium on utility procurement from its own affiliates until adequate safeguards are fashioned.

2. The Temporary Moratorium Is Not Arbitrary and Does Not Violate Sempra's Right to Equal Protection of the Law

Sempra contends that the moratorium is unnecessary because the existing affiliate rules, the current required reporting of affiliate transactions, and the new procurement review group process adopted in D.02-08-071 constitute adequate safeguards. Because the moratorium is unnecessary, in Sempra's view, it is arbitrary. (Sempra App. Rhg. of D.02-10-062, pp. 5-7.) For the reasons just discussed, we have reason to believe that current safeguards are inadequate for current conditions.

Sempra contends further that the fact that R.01-01-011 has been stayed since April 2001 is an indication that imposition of the moratorium is arbitrary. (Sempra App. Rhg. of D.02-10-062, p. 5.) Sempra incorrectly infers from the stay in that proceeding that we are unconcerned about fashioning appropriate safeguards against affiliate self-dealing in the procurement context. Adequate safeguards against affiliate abuses in energy procurement is an extremely important issue, as we pointed out early in this proceeding, and we fully intend to address it. Whether we address it in R.01-01-011 or in the long-term procurement phase of this proceeding is nothing more than a case management decision, as most parties seem to realize. (See ALJ Allen Ruling of April 4, 2003 in this proceeding re Confidentiality of Information and Effective Public Participation, p. 11.)[12] This decision will be made by the Administrative Law Judge

[12] The ruling notes that:

> [t]he Joint Parties agree that the issue of whether PPAs [power purchase agreements] with affiliates should be disclosed publicly should be addressed in whatever proceeding considers the lifting of that moratorium. If a proceeding does directly address the lifting of the current moratorium, the issue of disclosure of PPAs with affiliates may be

Division in consultation with the Assigned Commissioner. The inference Sempra draws is unwarranted.

Sempra also contends that the moratorium violates the equal protection rights of utility affiliates because it is arbitrary and not justified by any legitimate governmental objective. (Sempra App. Rhg. of D.02-10-062, p. 8.) Ensuring that electric rates are just and reasonable is one of our responsibilities. (See Pub.Util. Code § 451; see also § 454.5(d)(5).) Protecting ratepayers from imprudent payments by utilities to their affiliates is part of this responsibility. (See §§ 797-798; 454.5(h).) This is a legitimate government interest. There is no merit to Sempra's equal protection argument.

3. Dormant Commerce Clause

Sempra also contends the moratorium violates the dormant commerce clause. Sempra acknowledges that the moratorium applies evenhandedly to in-state and out-of state affiliates, but contends that the "incidental burdens" it places on interstate commerce are "clearly excessive in relation to the putative local benefits." (Sempra App. Rhg. of D.02-10-062, pp. 9-10, citing *Pike v. Bruce Church* (1970) 397 U.S. 137.) Sempra again dismisses the importance of the "interests supposedly served" by the moratorium, repeating its argument that existing rules are adequate. (Sempra App. Rhg. of D.02-10-062, p. 11.) This claim too lacks merit.

Sempra discounts the legitimacy of the interest involved here, just as it does in making its Equal Protection argument. And it exaggerates the incidental burden on interstate commerce. The moratorium does not "flatly prohibit transactions between certain buyers and sellers," as Sempra asserts (App. Rhg. of D.02-10-062, p. 10). Anonymous transactions between affiliates conducted through the Independent System Operator (ISO) are not precluded, as stated in the decision. In this order, we extend that

---

addressed in that proceeding. If the moratorium is lifted without a proceeding (by passage of time, for example), or if the issue of disclosure is not addressed in the proceeding that lifts the moratorium, then PPAs with affiliates shall be publicly disclosed in their entirety. At such time as the issue becomes ripe, a motion may be brought in this proceeding or before the law and motion ALJ to seek confidential treatment of such PPAs.

avenue to anonymous transactions conducted through brokers and exchanges. Thus, our moratorium does not preclude all power purchases from affiliates, and the incidental burden on interstate commerce is quite limited. We have already discussed the importance of preventing affiliate abuses in procurement. This is a far more serious interest than the State of Arizona's interest in having all cantaloupes grown in Arizona identified as coming from Arizona. The Supreme Court in *Pike* found that to be a legitimate, but "tenuous" local interest. (*Pike*, 397 U.S. at 145.) In contrast, the incidental burden on interstate commerce caused by our temporary moratorium on energy procurement from a utility's affiliates is not "clearly excessive" in relation to the legitimate interest it serves.

4. Notice and Opportunity To Be Heard

The Assigned Commissioner's Scoping Memo of April 4, 2002 (see p. 10) put the parties on notice that a moratorium on affiliate transactions was under consideration. Parties had an opportunity to comment on the moratorium, which was discussed both in Administrative Law Judge (ALJ) Walwyn's proposed decision and alternate decision that was ultimately voted out in October. Thus, there is no merit to Sempra's assertion that we adopted the moratorium without providing notice and an opportunity to be heard.

5. Preemption

Sempra contends that the moratorium is preempted by federal law, specifically, the Federal Power Act (16 U.S.C. § 824 et seq.) Sempra argues that the moratorium is preempted because the Federal Energy Regulatory Commission (FERC) has "completely and preemptively occupied the field of electric market entry and participation" and wholesale electric sales and because it "interferes with FERC rules governing market entry and participation in the wholesale power market" (Sempra. App. Rhg. of D.02-10-062, p. 12.) These contentions lack merit.

FERC has not "occupied the field" with respect to monitoring utility-affiliate transactions involving wholesale power sales. State commissions have undisputed regulatory authority over utility purchasing decisions, at least to the extent they do not conflict with FERC decisions specifically allocating power among utility purchasers or requiring utilities to purchase power from specified sources. (See *Kentucky West Virginia Gas Co. v. Pennsylvania Pub. Util. Comm'n* (3rd Cir. 1988) 837 F.2d 600; *Central Vermont Public Service Corp.* (FERC Aug 21, 1988), 84 FERC ¶61,194, 1998 FERC Lexis 1677.) As PG&E acknowledges in its application for rehearing, "state commissions have authority over certain aspects of affiliate transactions, such as administering a code of conduct and monitoring for market power abuses, as long as the state's provisions are consistent with and do not conflict with the FERC's marketing affiliate rules and code of conduct requirements." (PG&E App. Rhg. of D.02-10-062, p. 21.) In this proceeding, no party has challenged this Commission's authority to promulgate, amend, or enforce its own affiliate rules. In fact, Sempra argues repeatedly that our current rules provide adequate safeguards, obviating the need for the moratorium.

In the exercise of our state law authority, we have long regulated affiliate transactions related to power purchases by utilities, even though the FERC also has rules governing affiliate transactions. AB 57 expressly left our authority to oversee affiliate transactions unchanged:

> Nothing in this section alters, modifies, or amends the commission's oversight of affiliate transactions under its rules and decisions or the commission's existing authority to investigate and penalize an electrical corporation's alleged fraudulent activities, or to disallow costs incurred as a result of gross incompetence, fraud, abuse, or similar grounds.

(§ 454.5(h).)

The moratorium is a valid exercise of our authority to regulate utility power purchasing practices, and is not preempted.

C. Other Standards of Conduct Governing Procurement

In the October decision we adopted seven "standards of behavior" (also referred to as standards of conduct) governing utility procurement activity. PG&E, Edison, SDG&E, Sempra, CAC, and IEP each challenge some or all of these standards.

SDG&E argues that "all of the standards should be eliminated because they violate the AB 57 prohibition against hindsight reasonableness review." (SDG&E App. Rhg. of D.02-10-062, pp. 3-7.) SDG&E also contends that the standards are redundant and unsupported by findings justifying the need for them. All of the applicants express concern that the standards conflict with the goal of "certainty" underlying AB 57 and could, in effect, permit after-the-fact reasonableness review by the Commission, in violation of AB 57.

In our December decision we modified Standards 2 and 6, attempted to clarify certain points raised by the parties regarding Standards 4 and 7, and lifted Standard 6 for contracts for less than 12 months. SDG&E, in its application for rehearing of the December decision, argues again that *all* standards of conduct should be eliminated. The other applicants challenge Standards 4 (prudent administration of contracts and least-cost dispatch), 6 (contracts subject to modification by the Commission) and 7 (contracting parties must agree to give Commission access to information regarding compliance with standards).

Standards 6 and 7 differ from the other standards in that they were intended to be incorporated into procurement contracts under the IOUs' short-term procurement plans. The utilities have reported much resistance from potential suppliers to these standards. On December 30, 2002, in response to an emergency motion from SDG&E, we exempted from Standard 7 procurement contracts entered into to satisfy the requirements of the first quarter of 2003. (D.02-12-080.) In response to an emergency motion filed by PG&E on January 29, 2003, we extended this exemption to short-term procurement contracts entered into through the first quarter of 2004. (D.02-03-024.) In a separate decision we are issuing today, addressing Edison's February 3, 2003 Petition for Modification of D. 02-12-074 (agenda item #2023/#2057/#2296), we eliminate Standards 6 and 7 for purposes of the three utilities' short-term procurement plans.

Legal challenges to each of the Standards of Conduct raised in the applications for rehearing are discussed in order below.

1. Standard 1: Arms-length transactions, no self-dealing to the benefit of a utility or an affiliate

Only SDG&E and Sempra challenge Standard 1, which provides:

> Each utility must conduct all procurement through a competitive process with only arms-length transactions. Transactions involving any self-dealing to the benefit of the utility or an affiliate, directly or indirectly, including transactions involving an unaffiliated third party, are prohibited.

SDG&E and Sempra complain "self-dealing" and "benefit" are undefined and, as a result, the standard is vague. These applicants express concern that the scope of prohibited transactions that "indirectly benefit" a utility and affiliates is undefined. Sempra states that it would not object to Standard 1 if it is construed narrowly, to prohibit an affiliate "from obtaining benefits beyond those that are legitimately the fruits of an arms-length transaction." (Sempra App. Rhg. of D.02-10-062, p. 17.) If the standard is construed "broadly" to ban any utility transaction that involves an affiliate, Sempra opposes it for the reasons it opposes the moratorium on affiliate transactions. Sempra requests that the standard be eliminated or, in the alternative, that the scope of the prohibition against "self-dealing to the benefit of a utility or an affiliate" be clarified, and that the Commission state that the prohibition applies only to transactions in which an IOU, by transacting with an affiliate, obtained or provided a "material benefit not equally shared by ratepayers." (Sempra App. Rhg. of D.02-10-062, p. 17.)

SDG&E contends that the lack of clarity in the standard violates due process by not giving adequate notice of the scope of prohibited transactions. Among other objections, SDG&E points out that the prohibition is not limited to transactions where the utility knows that an affiliate "might 'benefit,' and therefore it is impossible for a utility to know whether entering into a particular transaction could subject the utility to liability." (SDG&E App. Rhg. of D.02-10-062, p. 9.) As an example, SDG&E states it is unclear how the standard would apply when it buys power through a competitive bidding process from a generator that obtains its natural gas, transportation, or storage services from an affiliate of SDG&E. (SDG&E App. Rhg. of D.02-10-062, p. 10.) SDG&E also contends that if construed very broadly, Standard 1 also burdens interstate commerce in violation of the Commerce Clause, by preventing utilities from entering into transactions through interstate brokers or exchanges because the seller might be an affiliate. (SDG&E App. Rhg. of D.02-10-062, p. 12.)

In response to these concerns, we provide the following clarification. Standard 1 does not preclude the IOUs from entering into "anonymous" transactions through approved interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa. Under these circumstances, the risk of affiliate transaction abuses is minimal. It is our understanding that most, if not all, of the brokers and exchanges being used by the IOUs already structure the bidding so that it is anonymous. Thus, this standard imposes little, if any, burden on interstate commerce.

2. Standard 2: Employee code of conduct; noncompete agreements

Standard 2 requires the utilities to adopt and enforce a code of conduct for all employees engaged in the procurement process. In their applications for rehearing of the October Decision, the three utilities argue for the removal of a provision that would require them to:

> . . . ensure all employees with knowledge of its procurement strategies sign and later abide by a noncompetitive agreement covering a one year period after leaving [the] utility's employment.

(D.02-10-062, p. 50.)

The utilities object to this noncompete provision on the ground is that it could violate California's clear public policy against noncompetition agreements, codified in California Business and Professions Code section 16600. PG&E raised the same arguments in its petition for modification of the October decision.

In our December decision, we acknowledged that as a general rule, California law bars employers from requiring employees to sign agreements that preclude them from working for competitors in subsequent employment. As we also noted, restricting an ex-employee's use of trade secrets and confidential information is generally permissible, however. We modified Standard 2 to place explicit emphasis on protection of trade secrets and confidential information, and qualified the reference to noncompete agreements, encouraging the utilities to use them "to the extent such covenants are lawful under the circumstances." (D.02-12-074, p. 57.) These modifications appear to have adequately addressed the legal concerns raised in applications for rehearing of the October decision.

3. Standard 3: No misrepresentations in filings for approval of procurement transactions

Only SDG&E challenges this standard, on the ground that it is duplicative (of Rule 1 and various statutes, including AB 57) and therefore unnecessary, and potentially confusing. This is not a claim of legal error. It is not unlawful to set forth applicable standards in a specific context. Doing so provides clear notice of the applicable standards (which SDG&E argues is indispensable in the context of Standard 1.) This claim lacks merit.

4. Standard 4: Prudent contract administration and least-cost dispatch

PG&E, Edison, and SDG&E challenge the validity of Standard 4 in their applications for rehearing of both the October and the December decisions. As set forth in the October decision, Standard 4 states:

> The utility shall prudently administer all contracts and generation resources and dispatch the energy in the least-cost manner. Our definitions of prudent contract administration and least cost dispatch is [sic] the same as our existing standard.

(D.02-10-062, p. 51.) In order to clarify Standard 4, the Commission added the following language in the December decision:

> For standard #4, to provide specific guidance in the procurement plans, we add the following language:

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation in which the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. PG&E's description of least-cost economic dispatch methodology described in its 1992 "Resource: An encyclopedia of energy utility terms," 2d edition, at pages 152-3 is appropriate with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations. The utility bears the burden of proving compliance with the standard set forth in its plan.

(D.02-12-074, pp. 52-53, 74.)

These modifications did not render the legal challenges raised in the October applications for rehearing moot. In their applications for rehearing of the December decision, the utilities repeat their original arguments and raise new issues in response to the modifications.

a) Whether Subsequent Review for Least-Cost Dispatch Is Precluded by Section 454.5(d)(2)

As stated above, Public Utilities Code section 454.5(d)(2) provides that a procurement plan approved by the Commission shall accomplish, among other things, the following:

> Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurements contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved.

The utilities contend that Standard 4 violates section 454.5(2) by imposing "after-the-fact reasonableness reviews."

As in any case involving statutory interpretation, the fundamental task is to determine the Legislature's intent so as to effectuate the law's purpose. (*People v. Murphy* (2001) 25 Cal.4th 136, 142.) The first step is to examine the statute's words, giving them a plain and commonsense meaning. (*Garcia v. McCutcheon* (1997) 26 Cal.4th 469, 476.) If the plain language of the statute is clear and unambiguous, there is no need to look beyond the words as an expression of Legislative intent. (*White v. Ultramar* (1999) 21 Cal.4th 563, 572.) However, the "plain meaning" rule does not mean that the statutory language is considered in isolation. The words must be construed in context, keeping in mind the nature and obvious purpose of the statute. (*Lungren v. Deukmejian* (1988) 45 Cal.3d 727, 735.)

A statute is considered ambiguous if it is capable of two constructions, both of which are reasonable. (*Hughes v. Board of Architectural Examiners* (1998) 17 Cal.4th 763, 776.) When a statute is ambiguous, a court may examine a variety of extrinsic aids, such as legislative history, public policy, contemporary administrative construction, and the statutory scheme of which the provision is a part. (*People v. Rubalcava* (2000) 23 Cal. 4th 322, 328,) "In the end, '[w]e must select the construction that comports most closely with the apparent intent of the Legislature, with a view to promoting rather than defeating the general purpose of the statute, and avoid an interpretation that would lead to absurd consequences.'" (*Ibid*., quoting *People v. Jenkins* (1995) 10 Cal.4th 234, 246.)

Contrary to the utilities' characterization, Standard 4 does not impose traditional after-the-fact reasonableness reviews. Standard 4 does not allow the Commission to conduct after-the-fact review of the terms or prices of the contracts themselves. In the December decision, the Commission clarified that contract terms and prices would not be at issue in any review under Standard 4. Rather, Standard 4 establishes a standard for dispatching energy. This standard is not tied to the contracts themselves; rather it applies to all generation resources.

Least-cost dispatch is an up-front standard that is included in the procurement plans. Any subsequent review of dispatch merely ensures that the utilities have complied with the approved procurement plans. Nothing in section 454.5 prohibits the Commission's review of utility actions to determine whether the utility complied with an approved procurement plan. Indeed, the statute states that a procurement plan shall eliminate the need for after-the-fact reasonableness reviews of a utility's actions *in compliance* with an approved procurement plan. (§ 454.5(d)(2).)

Moreover, according to its plain language, section 454.5 applies to the "procurement" of energy, rather than to dispatch. The main focus of the statute is "procurement transactions" and "procurement contracts." (See, e.g., §§ 454.5(c)(3), 454.5 (d)(2).) The legislative history of section 454.5(d)(2) indicates that the Legislature's intent in enacting the statute was only to eliminate after-the-fact review of the procurement contracts themselves. (See, e.g., Assem. Floor Analysis, Assem. Bill No. 57 (2001-2002 Reg. Sess.) as amended June 24, 2002.) Nothing in the statute, nor its legislative history, indicates that the Legislature intended the statute to apply to dispatch of energy. Thus, any subsequent review of dispatch is not precluded by section 454.5(d)(2).

As ORA argued in its response to the applications for rehearing of the October decision, the least-cost dispatch standard is not limited to contracts. The least-cost dispatch standard "involves management of the whole portfolio, including whether the dispatchable contracts were utilized in an optimum manner as compared to other utility resources." (ORA Response to Applications for Rehearing of D.01-12-074, p. 3.) Thus, least-cost dispatch applies to the DWR contracts allocated in D.02-09-053, to utility retained generation (URG) and pre-existing power contracts, and to new resources obtained pursuant to the approved procurement plans. (See D.02-09-053, p. 37; D.02-10-062, p. 51; D.02-12-074, pp. 52-53; see also D.02-04-016, p. 87, FF 13 and 14.)

Furthermore, support for Standard 4 is also found in other portions of the statute. As well as eliminating the need for after-the-fact reasonableness reviews, the statute requires that any approved procurement plan ensure "just and reasonable rates. (Pub. Util. Code §§ 454.5(d)(1) and 454.5(d)(5).) This mandate, which mirrors the Commission's continuing obligation to comply with Public Utilities Code section 451, is ignored in the arguments made by the utilities. The Commission's responsibility to ensure just and reasonable rates supports subsequent reviews based on the least-cost dispatch standard. Furthermore, AB 57 states that the intent of the bill is to direct the Commission "to assure that each electrical corporation optimizes the value of its overall supply portfolio," including DWR contracts and procurement pursuant to section 454.5, "for the benefit of its bundled service customers." (Assem. Bill No. 57 (2001-2002 Reg. Sess.) § 1(d).) Standard 4 is also consistent with this expression of legislative intent.[13]

b) Whether the Definition of Least-Cost Dispatch Is Appropriate

PG&E, Edison and SDG&E also challenge the October decision on the ground that Standard 4, which requires the utilities to "prudently" administer all contracts and generation resources and dispatch energy in a "least-cost manner," is unlawfully vague. In the December decision, the Commission attempted to address this concern by adopting more specific guidance, part of which was taken from a 1992 PG&E publication entitled "Resource: An encyclopedia of energy utility terms." (D.02-12-074, pp. 52-53.)

[13] Some parties have asserted that the Commission may not rely on the intent provisions of AB 57 because that bill was superseded by SB 1976. Government Code section 9605 provides that when the same section or part of a statute is amended by two acts enacted in the same session, it is presumed, in the absence of any express provision to the contrary, that the statute which is enacted last is intended to prevail over the statute enacted earlier and the statute which has a higher chapter number is intended to prevail over a statute with a lower chapter number. To the extent that SB 1976 altered AB 57, SB 1976 would prevail. However, section 9605 also states: "Where a section or part of a statute is amended, it is not considered as having been repealed and reenacted in the amended form. The portions which are not altered are to be considered as having been the law from the time when they were enacted." Thus, it appears that AB 57 is not supplanted entirely by SB 1976.

In any event, for the purpose of ascertaining the legislative intent of a revised statute, reference may be made to the prior statute. (*Pacific Gas and Electric Co. v. Industrial Accident Comm'n* (1932) 124 Cal.App. 303, 310.) Therefore, the Commission may refer to AB 57 in determining the intent of the Legislature in enacting section 454.5. It is also noteworthy that the Legislature's intent with respect to the procurement provisions is set forth only in AB 57; the intent section of SB 1976 deals solely with the feasibility of implementing real-time pricing.

However, the utilities continue to object to this standard, as well as the specific definition of least-cost dispatch adopted by the decision.

Edison objects to using the definition of least-cost dispatch as contained in PG&E's publication because (1) the document is not a part of the record of this proceeding and (2) the definition contained in the document is not appropriate for today's market. PG&E and SDG&E contend that Standard 4 is still insufficiently detailed to meet the "up-front" standards required by section 454.5(c)(3). While ORA supports the least-cost dispatch standard, in general, ORA agrees with Edison that the definition is not applicable in today's market.

These arguments have persuaded us to modify D.02-12-074 to eliminate references to PG&E's publication. However, the least cost-dispatch standard itself, as adopted in D.02-10-062, and as elaborated on in D.02-12-069 and D.02-12-074, is left intact. We reject the utilities' arguments that Standard 4 is unlawfully vague. No party has presented a more detailed standard that would still allow the Commission to meet its mandate of ensuring just and reasonable rates.

c) Whether Standard 4 Violates Public Utilities Code Section 454.5(c)

In its application for rehearing of the October decision, Edison claims that Standard 4 also violates section 454.5(c), which provides that the Commission may not approve a feature or mechanism as part of a procurement plan

> if it finds that the feature or mechanism would impair the restoration of an electrical corporation's creditworthiness or would lead to a deterioration of an electrical corporation's creditworthiness.

Edison contends that the decision errs because it does not consider the impact of Standard 4 on the utility's creditworthiness. Edison further asserts that the record is filled with testimony from utilities and other witnesses that discuss the financial risk posed by continuation of after-the-fact reasonableness reviews.

Specifically, Edison cites testimony of Edison's Chief Financial Officer James Scilacci (Edison's Testimony on Procurement Issues, filed May 1, 2002, Volume I,

p. II-16) and a declaration of Susan Abbott, former managing director of the Power Group at Moody's Investor Service (Declaration of Susan Abbott, filed November 12, 2002, p. 47). These statements discuss the extreme situation in which Nevada Power Company's ratings were downgraded after the Nevada Public Utilities Commission disallowed recovery of almost one-half of the company's purchased power costs (amounting to $437 million). In addition, the statements appear to apply to after-the-fact reviews of contract terms and prices. Thus, the situation addressed by these statements is distinguishable from the more limited review at issue in the instant decision.

Furthermore, although the October decision did not make any findings as to whether Standard 4 would adversely impact an electrical corporation's creditworthiness, the Commission did consider the impact of Standard 4 in the December decision. In that decision, the Commission noted that reviews for prudent contract administration and least-cost dispatch have not been the cause of significant disallowances in the past, and would not likely be so in the future. (D.02-12-074, p. 53.) In addition, the December decision adopted a cap on potential disallowances "in order to support the utilities' quicker return to creditworthiness." (D.02-12-074, pp. 53-54.) The Commission has further refined the cap in response to Edison's request to specify a dollar limit for disallowances. (See Edison's Pet. Mod. of D.02-12-074, filed February 3, 2003.)

Even assuming that "[a]fter-the-fact prudence reviews may introduce uncertainty into a situation," (see Edison App.Rhg. of D.02-10-062, p. 6), Edison has not demonstrated that the limited compliance review imposed by the decision "would impair the restoration of an electrical corporation's creditworthiness or would lead to a deterioration of an electrical corporation's creditworthiness." As stated previously, the review imposed by the decision involves after-the-fact review of dispatch decisions and not review of the contract terms or prices. For all of these reasons, Edison's argument that Standard 4 violates section 454.5(c) is not convincing.

d) Whether the Commission's Review Processes Violate Public Utilities Code Section 454.5

As part of its challenge to Standard 4, Edison contends that the October decision errs in establishing insufficient review processes. Edison asserts that the Commission's review of advice letter filings for transactions entered into in accordance with an approved procurement plan must be expeditious and must be broadened to encompass all of a utility's procurement activities. Specifically, Edison states that, although calling for expedited compliance filings, the October decision does not state how quickly the Commission will act to resolve any issues. (See D.02-10-062, p. 46.) In addition, Edison asserts that the scope of the filings appears to be limited to contract formation issues and contends that the scope must be broadened to include all utility procurement activities, including dispatch of a utility's entire portfolio of resources. Edison claims that failure of the decision to require timely review and resolution of all utility procurement activities will impede the utilities' return to creditworthiness in violation of section 454.5(c). Edison also points out that the body of the decision adopts a quarterly compliance schedule, while Appendix B refers to monthly advice letters.

Edison argues that this same problem applies to the Commission's provision for semiannual updates for contract administration, URG expenses, and least-cost dispatch. (See D.02-10-062, p.63.) Edison contends that these issues should be reviewed in quarterly compliance filings and that the Commission must establish a firm and expeditious schedule for timely resolution of these issues in order to meet the creditworthiness requirements of section 454.5(c).

First, the advice letter filings for transactions entered into in accordance with an approved procurement plan are intended to be quarterly filings. We will modify Appendix B of the October decision to refer to quarterly rather than monthly advice letters. Second, Edison has not demonstrated that expedited review pursuant to the least-cost dispatch standard is required to meet the creditworthy requirements of section 454.5(c). Third, regarding the timing for review of the quarterly filings, the Commission addressed this issue in the December decision. The Commission rejected Edison's proposal that review must be completed in 15 days and that a final Commission decision must be issued within 45 days of the date of filing. The Commission found that a 15-day review period is too brief, given the Commission's resources and the fact that three utilities would be simultaneously filing quarterly advice letters. Instead, the Commission found that a 30-day review period is more reasonable. At the end of that period, the staff would have 15 days to prepare a resolution and place it on the agenda for the next Commission meeting. The Commission noted that these timeframes are "guidelines." (D.02-12-074, pp. 46-47.)

In its application for rehearing of the December decision, Edison continues to argue that the timelines are inadequate because they do not set any time limit for the Commission to resolve the issues. However, Edison relies on section 454.5(d)(3), rather that the creditworthiness requirements of section 454.5(c). Section 454.5(d)(3) requires a procurement plan approved by the Commission to "[e]nsure timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan."

The requirements imposed by section 454.5(d)(3) deal with the recovery of *prospective* costs through procurement balancing accounts. The quarterly filings for transactions entered into in accordance with an approved procurement plan do not affect cost recovery on a prospective basis because potential disallowances do not interfere with the operation of the 5 percent trigger mechanism for amortizing undercollections. Similarly, the annual compliance review for least cost dispatch and contract administration does not impact the cost recovery on a prospective basis, given the operation of the 5 percent trigger threshold.[14] Thus, Edison has not demonstrated legal error.

[14] This review includes a filing and proceeding for setting rates, and is followed six months later with a review of balancing accounts, contract administration, URG expenses, and least-cost dispatch. Although this is referred to as a "semi-annual" update process, the review actually occurs only once a year. (See D.02-10-062 at p. 63.)

e) Whether Standard 4 Violates Water Code Section 80110

PG&E argues that Standard 4 also violates Water Code section 80110 by not excluding DWR contracts from the Commission's least-cost dispatch review. Section 80110 states, in part, that the Commission's authority as set forth in Public Utilities Code section 451 shall apply, "except any just and reasonable review under Section 451 shall be conducted by [DWR]." PG&E incorporates by reference its application for rehearing of D.02-09-053, which allocated existing DWR contracts to the utilities.

As stated in the order disposing of applications for rehearing of D.02-09-053 (agenda item #2129), the Commission's review of the utilities' compliance with an approved procurement plan under Public Utilities Code section 454.5 is distinct from review of DWR's revenue requirement under Water Code section 80110 and Public Utilities Code section 451. The section 454.5 compliance review established in D.02-09-053 for DWR contracts, and reiterated in Standard 4 of the October decision, would allocate costs between ratepayers and shareholders – it has no impact on DRW's revenue requirement. Thus, PG&E has not demonstrated a violation of Water Code section 80110.

5. Standard 5: No fraud, abuse, negligence or gross incompetence in negotiating procurement transactions or administering contracts and generation resources

The discussion under Standard 3, above, is applicable to Standard 5 as well.

6. Standard 6: Contracts must acknowledge that terms are subject to modifications ordered by CPUC

As modified by the December decision, Standard 6 requires:

> For all contracts with terms between 12 and 60 months, all contracts must contain the following revision: "In the event of statutory or federal regulatory changes, this contract shall be subject to such changes or modifications as the CPUC may direct."

(D.02-12-074, p. 75, OP 24.)

Edison, PG&E, SDG&E, Sempra, and CAC all oppose this standard, even as modified. Because we are eliminating this standard for purposes of the short-term procurement plans in a separate decision issued today, the objections to Standard 6 are moot. Whether some form of "regulatory out" clause should be required for purposes of long-term procurement plans is an issue that may be addressed in the long-term procurement planning phase of this proceeding.

7. Standard 7: Contracting parties must agree to give the Commission access to information regarding compliance with Standards of Conduct

Standard 7 requires that:

> . . . all contracting parties to a procurement contract must agree to give the Commission and its staff reasonable access to information within seven working days, unless otherwise practical [sic], regarding compliance with these standards.

(D.02-10-062, p. 73, OP 11.)

In response to parties' objections to Standard 7, we clarified in the December decision that:

> The concerns of parties regarding standard 7 are based on a misunderstanding of the requirement. We do not seek unlimited discovery but rather seek only information demonstrating compliance with the approved behavior standards at the time of the contract execution.

Notwithstanding this qualifying language, Edison, in its application for rehearing of the December decision, asserts that Standard 7 is "patently illegal." (Edison App. Rhg. of D. 02-12-074, p. 11.) Because we are eliminating Standard 7 for purposes of short-term procurement plans in a separate decision issued today, the legal objections to this requirement are moot. Nevertheless, because the issue may reappear in the context of long-term procurement, we observe that we have authority, pursuant to the Federal Power Act, to inspect the books and records of generating facilities owned by exempt wholesale generators that sell power to Commission-regulated utilities, when necessary for purposes of state regulation. (See 16 U.S.C. section 824(g) [15]; see also *Bristol Energy Corp. v. New Hampshire Pub. Utilities Comm'n* (1st Cir. 1994) 13 F.3d 471, 477; Commission Resolution L-293 (review denied in *Mirant Delta, Inc. et al. v. CPUC*, No. A095743, December 4, 2001).)

We also have ample independent authority under state law to require information from energy suppliers, based on our broad authority to regulate public utilities, which includes the authority to investigate matters pertaining to public utility regulation. (See *SDG&E v. Superior Court* (1996) 13 Cal.4th 893, 915 (quoting *Consumers Lobby Against Monopolies v. Public Utilities Comm'n* (1979) 25 Cal.3d 891, 905 (discussing source of Commission authority under Article XII of the California Constitution and Public Utilities Code section 701).) In addition to our broad authority under the Constitution and section 701, the Commission has specific authority under Public Utilities Code section 311 to subpoena records and testimony needed for an investigation. Thus, eliminating Standard 7 as a required contract term will not deprive the Commission of its authority to obtain information directly from the utilities' power suppliers, when necessary.

D. Resource Options

1. Renewable Resources

PG&E and Edison allege error in both the October and the December decisions on issues involving procurement of renewables.

---

[15] 16 U.S.C. § 824(g) provides, in part:

(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of—

(A) an electric utility company subject to its regulatory authority under State law,

(B) an exempt wholesale generator selling energy at wholesale to such electric utility, and

(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A), wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

a) Background

In D.02-08-071, the Commission granted transitional authority to the utilities to immediately contract for a portion of their residual net short (RNS) in partnership with DWR. In that same decision, the Commission required the utilities to hold a separate competitive solicitation for renewable resources in the amount of at least an additional one percent of their annual electricity sold beginning January 1, 2003. (D.02-08-071, p. 32.) The basis for these requirements is the Commission's authority under Public Utilities Code section 701.3, which states:

> Until the commission completes an electric generation procurement methodology that values the environmental and diversity costs and benefits associated with various generation technologies, the commission shall direct that a specific portion of future electrical generating capacity needs for California be reserved or set aside for renewable resources.

D.02-08-071 also refers to SB 1078, which was signed by the Governor on September 12, 2002. SB 1078 enacted the California Renewables Portfolio Standard Program (RPS), which, among other things, requires the Commission to implement annual targets for renewable energy for each electrical corporation. Beginning January 1, 2003, each electrical corporation is required to increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year, with a goal of procuring 20 percent of its retail sales from renewable resources no later than December 31, 2017. (Pub. Util. Code § 399.15(b)(1).)

In the October decision, the Commission reiterated the renewables requirement contained in D.02-08-071 and stated that the requirement should be adhered to, "with or without DWR credit support." (D.02-10-062, p. 23.) The October decision also stated that utilities are required to contract for this amount of electricity from renewable sources "by the end of 2002." (D.02-10-062, p. 23.)

In the December decision, the Commission again addressed the renewables requirement. The Commission found that PG&E appeared to have met its 1 percent interim renewable requirement, "pending final certification by the CEC [California

Energy Commission] of the incremental output from existing resources per SB 1078." (D.02-12-074, p. 23.) The Commission noted that Edison had not yet filed an advice letter pursuant to D.02-08-071 and therefore "is in noncompliance with D.02-08-071." (D.02-12-074, p. 26.)

b) PG&E's Allegations

(1) The October Decision

PG&E alleges that the October decision errs in requiring the renewable requirement to be adhered to "with or without DWR credit support" (see D.02-10-062, p. 23), despite the fact that the authority granted to PG&E and Edison in D.02-08-071 was for contracts that would have had DWR support. PG&E also objects to the 1 percent requirement that was adopted in D.02-08-071 and repeated in the October decision.

The utilities had the opportunity to meet the renewables requirement with DWR support. However, in the event that the utilities did not meet the 1 percent renewables target by the end of 2002, they would still be required to do so in 2003, when DWR support would no longer be available. Therefore, the "with or without DWR credit support" language was inserted in the decision.

Regarding the 1 percent requirement, PG&E primarily relies on Edison's arguments in its application for rehearing of D.02-08-071. Edison's arguments are addressed in the order disposing of the applications for rehearing of D.02-08-071 (agenda item #2128).

In any event, it appears that these issues are now moot. By the time D.02-12-074 was issued, PG&E had filed its advice letter on the transitional renewables contracts. (D.02-12-074, p. 23.) PG&E's advice letter was approved by the Commission in Resolution E-3805, issued on December 19, 2002.

(2) The December Decision

In its application for rehearing of the December decision, PG&E objects to the "new requirement" that the renewable energy that PG&E has procured must be certified as "incremental" by the California Energy Commission (CEC). (See D.02-12-

074, pp. 23-24.) PG&E's argument has merit. The CEC certification requirement is taken from SB 1078, which we explicitly stated was not the basis for the Commission's mandate regarding transitional renewables contracts in D.02-08-071. Moreover, this requirement was added more than two months after the initial solicitation order. Therefore, we will modify the decision to eliminate the CEC certification requirement for interim procurement.

c) Edison's Allegations

(1) The October Decision

In its application for rehearing of the October decision, Edison contends that the decision repeats the error of D.02-08-071 by applying Public Utilities Code section 701.3 in disregard of other state and federal laws. In particular, Edison objects to a footnote in the decision that states:

> PG&E and Edison each contend that the Commission's authority to order renewable procurement will be confined to the mandates of SB 1078 on January 1, 2003. We disagree and hold, as CBEA [California Biomass Energy Alliance] contends, that SB 1078 does nothing to amend or limit the authority and direction conferred by Section 701.3, upon which we relied in ordering interim renewable procurement.

(D.02-10-062, p. 23, fn. 14.)

Edison claims that SB 1078 and Public Utilities Code section 454.5(b)(9)(A) mandate that procurement must be at prices which are at or below market, except insofar as additional funding is available from the Public Goods Charge (PCG). Section 701.3, on the other hand, does not articulate such limitations.

In its application for rehearing of D.02-08-071, Edison argued that D.02-08-071, which relies on Public Utilities Code section 701.3 in ordering the procurement of renewable resources, could be interpreted to require Edison to execute contracts with renewable suppliers offering to sell power at the benchmark price of 5.37 cents/kWh, without regard to expected market price and without regard to actual need. The issues raised in D.02-08-071 regarding the transitional contracts are now essentially moot.

Edison has executed contracts for renewable resources as directed in D.02-08-071. Furthermore, the significance of the benchmark price was clarified in the October decision (D.02-10-062, p. 23), and is also addressed in the decision resolving Edison's application for rehearing of D.02-08-071 (agenda item #2128).The contracts entered into pursuant to D.01-08-071 were and will continue to be governed by Public Utilities Code section 701.3. By the instant decision, we clarify that our statements in footnote 14 apply only to the interim procurement ordered in D.02-08-071. Footnote 14 is not intended to address how we will interpret the statutes for purposes of the current RPS process regarding the implementation of SB 1078.

(2) The December Decision

In its application for rehearing of the December decision, Edison argues that the decision errs in finding that Edison was not in compliance with D.02-08-071. (See D.02-12-074, pp. 26, 68, CL 17.) Edison points out that D.02-08-071 did not set a specific deadline for filing an advice letter for approval of transitional contracts for renewable resources. CBEA responds that D.02-08-071 makes it clear that contracts with existing renewables facilities must provide for delivery of power beginning January 2003. According to CBEA, because 30 days are required for approval of the advice letters, such advice letters had to be submitted by November 17, 2002 – 30 days prior to the December 17, 2002 Commission meeting.

As Edison itself acknowledges, this issue is now moot because Edison filed its advice letter on transitional renewables contracts on December 24, 2003. Nevertheless, because D.02-08-071 did not specify a filing deadline, we will modify the decision to state that, as of the date of the December decision, Edison had not yet complied with D.02-08-071. In addition, we will remove the threat of sanctions for noncompliance with D.02-08-071. However, the Commission will monitor the RPS process to ensure compliance with any future Commission directives regarding renewables.

Edison also contends that the December decision errs in adopting the same "flawed" reasoning of D.02-08-071 and D.02-12-074 regarding the relationship of between Public Utilities Code section 701.3 and other state and federal laws, including AB 1078 and Section 454.5. This argument is disposed of by the proposed clarification to footnote 14 of D.02-10-062, discussed above.

2. Demand Reserves Partnership Program

The October decision states that the California Power Authority (CPA) currently has a Demand Reserves Partnership program, under contract to DWR, to provide demand response resources through the ISO ancillary service market. The decision further states that this DWR contract is "assignable" from DWR to the utilities as part of their procurement plan.

> While we do not direct immediate contract assignment in this decision, we require the utilities to include the available resources in their long-term procurement plan, as well as a transition plan for eventual assignment of the contract if Commission approval occurs in the future.

(D.02-10-062, p. 28.)

PG&E and SDG&E contend that there has been no record established regarding the issue of responsibility and administration of this contract, nor the legal and factual basis for assigning this contract to the utilities. PG&E and SDG&E argue that the contract was not in evidence in this case and, according to PG&E, this topic did not appear until it was discussed in the ALJ Proposed Decision mailed September 24, 2002.

We recognize that, although the decision does not purport to assign the contract, the language used in the decision could be interpreted to prejudge the issue of assignment. Therefore, we clarify that notice and opportunity to be heard will be provided to the parties regarding the possible assignment of this contract before determining whether or not to do so.

3. Operating and Planning Reserve Requirements

PG&E and Edison object to the imposition of a provisional 15 percent total reserve requirement, as set forth in the October decision. Edison points out, correctly, that the term "reserve requirement" is not defined for purposes of the decision. Edison also contends that the parties had no notice that a planning reserve requirement for short-term procurement was being considered, and that there was no opportunity and no time to make an appropriate record and findings upon which to base a planning reserve requirement. Imposing the provisional planning reserve requirement without notice and without an adequate record, Edison argues, violates both Public Utilities Code section 1705 and Edison's right to due process. Edison proposes that the Commission withdraw the provisional requirement imposed in the October Decision and consider the issue of a planning reserve requirement as part of the long-term planning process. (Edison App. Rhg. of D.02-10-062, pp. 13-16.)

We agree that the establishment of an adequate planning reserve should be addressed in the context of long-term procurement planning. Our original intention in requiring a 15% provisional reserve requirement, as set forth in the October decision, was to require a 7% operating reserve (which is not being challenged) plus an 8% planning reserve. Thus, "reserve requirement" as used in that decision included both types of reserves. Subsequently, however, we reviewed and adopted, with modifications, the IOUs' modified procurement plans for 2003. These plans, as adopted, include a 7% operating reserve, but we decided during the review process not to require a planning reserve for these short-term plans. Today we clarify that we are not requiring a planning reserve for these short-term plans, contrary to what we stated in the October decision. Only a 7% operating reserve is required. Appropriate planning reserve levels will be considered in the long-term planning phase of this proceeding. Deferral of this question to the long-term phase renders moot Edison's arguments concerning lack of adequate notice and opportunity to comment. There will also be an opportunity to develop the record on this issue.

PG&E contends that a planning reserve requirement is premature and "interferes in an area entrusted to federal jurisdiction." (PG&E App. Rhg. of D.02-10-062, p. 29.) PG&E states that FERC, in the Standard Market Design proceeding, "is actively considering requirements and responsibility for reserve margins, such as whether load serving entities like PG&E, or the network operator like the ISO, should have the responsibility for obtaining the reserves." (PG&E App. Rhg. of D.02-10-062, p. 30.)

This contention is not entirely clear to us.[16] PG&E does not use the term "preempted" and cites no authority to support the proposition that imposition of a reserve requirement on the IOUs by the Commission is preempted by federal law at this time. Rather, PG&E seems to be suggesting that future actions by FERC *might* preempt Commission authority in this area. PG&E also argues that Commission reserve requirements may prove to be "useless and potentially very costly" if FERC places some of the responsibility for obtaining reserves on the ISO. (PG&E App. Rhg. of D.02-10-062, p. 30.) The first argument is speculative and unsupported by any legal authority. The second is equally speculative and does not constitute a claim of legal error. PG&E has failed to articulate a legal impediment to our establishing a planning reserve requirement as part of the procurement planning process.

E. Issues Relating to Procurement Transaction Options, Risk Management, and Ratemaking

1. Whether the Decisions Err in Requiring a Showing for Bilateral Transactions

The October decision authorizes the utilities to procure products using a number of different transactional methods (i.e., competitive bid process, purchases through transparent markets, inter-utility exchanges, ISO markets, and utility ownership). (D.02-10-062, p. 30.) In addition, the decision allows the utilities to use negotiated bilateral contracting, provided the utility can demonstrate that such bilateral transactions represent a reasonable approximation of what a transparent competitive market would

[16] Applicants for rehearing are required to set forth the specific ground(s) on which they contend the decision to be unlawful. (Pub. Util. Code § 1732.)

produce. (D.02-10-062, p. 34.) Edison asserts that this is not possible because there are certain non-standard products that can be obtained only by bilateral contracting; i.e., there are no competitive markets for such non-standard products. Edison further asserts that there is no evidence to support this requirement.

We addressed this issue again in the December decision. Noting that the utilities provided no alternative measurement tool, we suggested that the utilities may meet this standard by a comparison to Requests for Offers (RFO's) completed within one month of the transaction, or by updating their procurement plans. (D.02-12-074, p. 7.) In its application for rehearing of the December decision, Edison repeats its earlier arguments and contends that comparison to RFOs is infeasible and that updating its plan makes no sense. Because, according to Edison, it cannot meet the transparent market standard, Edison contends that the decision violates the section 454.5(c)(3) provision that requires "up-front achievable standards."

This issue is being addressed by the Commission in response to Edison's February 3, 2002 petition for modification of D.01-12-074 (agenda item #2023/#2057/#2296.) Therefore, this issue need not be resolved here.

2. Customers' Risk Tolerance Levels

Edison contends that the December decision unlawfully requires Edison to comply with unclear standards on the issue of customers' risk tolerance level. The decision states:

> We find ORA's proposed trigger mechanism, when used in conjunction with TURN's proposal, to be reasonable and will adopt these two mechanisms for each utility for the short-term procurement plans.

(D.02-12-074, p. 15; see also p. 62, FF 19.) Edison argues that it is unclear which risk tolerance proposals, or portions thereof, the December decision adopts.

This issue is being addressed by the Commission in response to Edison's February 3, 2002 petition for modification of D.01-12-074 (agenda item #2023/#2057/#2296). Therefore, this issue need not be resolved here.

3. Energy Resource Recovery Account

Section 454.5(d)(3) requires that, until January 1, 2006,

> the commission shall ensure that any overcollection or undercollection in the power procurement balancing account does not exceed 5 percent of the electrical corporation's actual recorded generation revenues for the prior calendar year, excluding revenues collected for DWR. The commission shall determine the schedule for amortizing the overcollection or undercollection in the balancing account to ensure that the 5 percent threshold is not exceeded.

PG&E contends that the October decision does not contain provisions that would ensure the balance in the Energy Resource Recovery Account (ERRA) is below the 5 percent threshold. The decision states that, instead of changing rates when the recorded balance in the ERRA reaches or exceeds 5 percent of the prior year recorded generation revenues, the utilities are directed to file expedited applications, for approval in 60 days from the filing date, when the new ERRA balance reaches 4 percent. (D.02-10-062, p. 64.) PG&E argues that nothing in the decision ensures that the ERRA balance would not exceed the 5 percent level, either through swift Commission action or a pre-approved rate adjustment mechanism.

In the December decision, the Commission addressed PG&E's concerns. Noting the somewhat unique position of PG&E as a bankrupt utility, the decision makes several changes to the October decision. (D.02-12-074, pp. 41-42.) Among other things, the decision states that PG&E may file an expedited application at any time that its forecasts indicate that it will face an undercollection in excess of 5 percent. That is, PG&E is not required to wait until its undercollections reach 4 percent. (D.02-12-074, p. 41.) PG&E did not raise this issue in its application for rehearing of the December decision. Therefore, it appears that this issue has been resolved.

4. Recovery of Electric Energy Transaction Administrative Costs

In its application for rehearing of D.02-10-062, PG&E argues that the decision should be modified to require recovery of its costs of administering and managing its electric procurement portfolio and procurement activities, designated as Electric Energy Transaction Administrative costs (EETA), in general rate cases (GRCs). PG&E contends that the October decision directs PG&E to record EETA costs in the ERRA balancing account. (D.02-10-062, Appendix D.) PG&E further states that this provision conflicts with D.02-09-053, which directed such costs for DWR contracts to be recovered through GRCs.

In the December decision, the Commission modified the October decision to exclude EETA costs from the ERRA. Instead, EETA costs are to be recovered through base rates in the GRC. (D.02-12-074, p. 45.) This modification renders PG&E's argument moot. However, Edison, which had argued that EETA should be included in the ERRA until such time as base rates are established to recover them, objects to the modification in its application for rehearing of the December decision. Edison claims that the December decision unlawfully fails to authorize an appropriate mechanism for recovery of EETA costs.[17] Edison points out that, although both Edison and SDG&E were directed to modify their ERRA account to exclude EETA costs, only SDG&E was allowed to track these costs in a memorandum account for later recovery. The reason for this, according to the decision, is that SDG&E's cost of service application is in the future. (D.02-12-074,p. 45.) Edison states that it must also be allowed to establish a memorandum account, effective January 1, 2003, to track EETA costs.

Edison should be given the same authority that SDG&E has to track these costs in a memorandum account. We will modify the decision to explain that, if Edison has not already included the EETA costs as part of its GRC application, it should do so. Edison should be permitted to establish a memorandum account to record actual costs of this activity pending the GRC decision. The forecast for the EETA activity should be established in the GRC as contemplated by D.02-09-053.

[17] Edison identifies such costs to include (1) procurement-related contract administration costs (mostly labor) and (2) system development costs (capital software) associated with Edison's new Residual Net Short (RNS) responsibility.

F. Sempra's Request for Oral Argument

Sempra requests oral argument on both the October and the December decisions. Sempra contends that its request should be granted because the applications for rehearing raise issues of major significance, and because the decisions depart from existing Commission precedent without adequate explanation and present legal issues of exceptional controversy and public importance. Sempra does not specify which issues it believes meet these criteria, however.

We are not persuaded that oral argument will materially assist the Commission in resolving Sempra's applications. Accordingly, the request for oral argument is denied. (See Rule 86.3(a) of the Commission Rules of Practice and Procedure.)

Therefore **IT IS ORDERED** that D.01-10-062 is modified as follows:

1. On page 10, delete the last sentence of the first full paragraph, that reads: "PG&E is presently is bankruptcy but under our proposed Plan of Reorganization, PG&E will be able to quickly emerge from bankruptcy as a creditworthy entity, because it will meet the quantitatively objective criteria for investment grade ratings."

2. On page 66, delete finding of fact 7, which states that many companies in the energy industry today do not have an investment grade credit rating and are nevertheless able to conduct business.

3. On page 67, delete finding of fact 11, regarding the Commission's proposed Plan of Reorganization.

4. On page 68, after finding of fact 20, insert the following additional findings of fact:

> 20a. A review of the three utilities' procurement costs that were disallowed between 1980 and 1996, before restructuring, shows that the largest disallowances for procurement costs, *in terms of dollar amounts*, involved affiliate transactions.
>
> 20b. Due to the holding company corporate structures within which the utilities operate, and due to the post-AB 1890 divestment of generation capacity by the utilities, the

risks of ratepayers subsidizing utility affiliates as a result of procurement transactions among affiliates is greater now than in the 1980-1996 time period.

5. On page 68, replace finding of fact 21 with the following revised finding:

21. It is reasonable to place a moratorium on Edison, PG&E, or SDG&E dealing with their own affiliates in procurement transactions, beginning January 1, 2003, to allow for a careful reexamination and appropriate modification of our affiliate rules. This moratorium will continue until we have made appropriate modifications to our affiliate rules applicable to procurement activities, or for two years, whichever date is first. Utilities may propose to include specific affiliate transactions in their procurement plans but these proposals may not be implemented until the end of the moratorium. Based on comments, we are persuaded that transactions through the ISO that can be demonstrated to include multiple and anonymous bidders are permissible. The moratorium also does not preclude anonymous transactions conducted through brokers and exchanges.

6. On page 69, after finding of fact 21, add the following finding:

21a. Standard of Conduct 1 does not preclude anonymous transactions conducted through the ISO or through brokers and exchanges.

7. On page 74, add the following conclusions of law:

19. AB 57 left unchanged our authority to regulate affiliate transactions.

20. The Federal Power Act does not preempt our authority under state law to prevent affiliate abuses in procurement of power by the electric utilities we regulate.

8. In Appendix B, delete the title and replace it with the following: "Adopted Master Data Request for Quarterly Advice Letters." In the first sentence of Appendix B, delete the word "month's" and replace it with "quarter's."

IT IS FURTHER ORDERED that D.01-12-074 is modified as follows:

9. On page 19, in the final paragraph, delete the third and fourth sentences and replace with the following:

> We have made a preliminary determination that the approved renewable generation amounts to incremental production, subject to the satisfaction of the contract terms.

10. On page 23, in the first full paragraph following the heading "PG&E," delete the final sentence of the paragraph and replace it with the following:

> Pending Commission approval of Resolution E-3805, it appears that PG&E has met its 1 percent interim renewable procurement mandate, as long as PG&E honors those contracts in 2003.

11. On page 24, at the end of the full paragraph on the page, delete the next to the last sentence and replace with the following:

> We will provisionally hold that PG&E has met its interim procurement goal.

12. On page 26, in the second paragraph, delete the sentence that reads: "We find that the utility is in noncompliance with D.02-08-071, and will address this noncompliance in a subsequent Commission order" and replace it with the following:

> As of the date of the instant decision, Edison has not yet complied with D.02-08-071.

13. On page 45, in the first full paragraph, following "d) Cost Recovery of Certain Costs," delete the last sentence and replace with the following:

> SDG&E and Edison should track Electric Energy Transaction Administrative (EETA) costs in a memorandum account for later recovery.

14. On pages 52-53, in the indented paragraph, delete the next to the last sentence that reads: "PG&E's description of least-cost economic dispatch methodology described in its 1992 "Resource: An encyclopedia of energy utility terms," 2d edition, at pages 152-3 is appropriate with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations."

15. On page 68, delete conclusion of law 17.

16. On pages 73-74, in ordering paragraph 24.b regarding prudent contract administration, delete the sentence that reads: "PG&E's description of least-cost

economic dispatch methodology described in its 1992 "Resource: An encyclopedia of energy utility terms," 2d edition, at pages 152-3 is appropriate with the recognition that a pure economic dispatch of resources may need to be constrained to satisfy operational, physical, legal, regulatory, environmental, and safety considerations."

IT IS FURTHER ORDERED that:

17. As modified by this order, the applications for rehearing of D.02-10-062 and D.02-12-074 are denied.

18. Sempra's request for oral argument is denied.

This order is effective today.

Dated June 19, 2003, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners